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(71) Applicant(s)
Institut Francais du Pétrole
(Incorporated in France)
4 avenue de Bois-Préau, 92852 Rueil-Malmaison Cedex, France

(72) Inventor(s)
Marie-Christine Cacas
Sylvain Sarda
Bernard Bourbiaux
Jean-Claude Sabathier

(74) Agent and/or Address for Service
Fitzpatricks
Cardinal Court, 23 Thomas More Street, LONDON, E1 9YY, United Kingdom

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(54) Abstract Title

Determining the equivalent permeability of a fracture network in a sub-surface,multi-layered medium

(57) The equivalent fracture permeability of a fracture network in a sub-surface, multi-layered medium is determined by dividing the fracture network into fracture elements (e.g. rectangles) and by defining nodes representing inter-connected fracture elements within each layer of the medium and determining fluid flows (e.g. steady-state flows) through the divided network, imposing boundary pressure conditions and fluid transmissivities at each pair of adjacent nodes. The method can be used to link fracture oil reservoir characterisation models systematically to dual porosity simulators with a view to building a more realistic model of a fractured, sub-surface geological structure.

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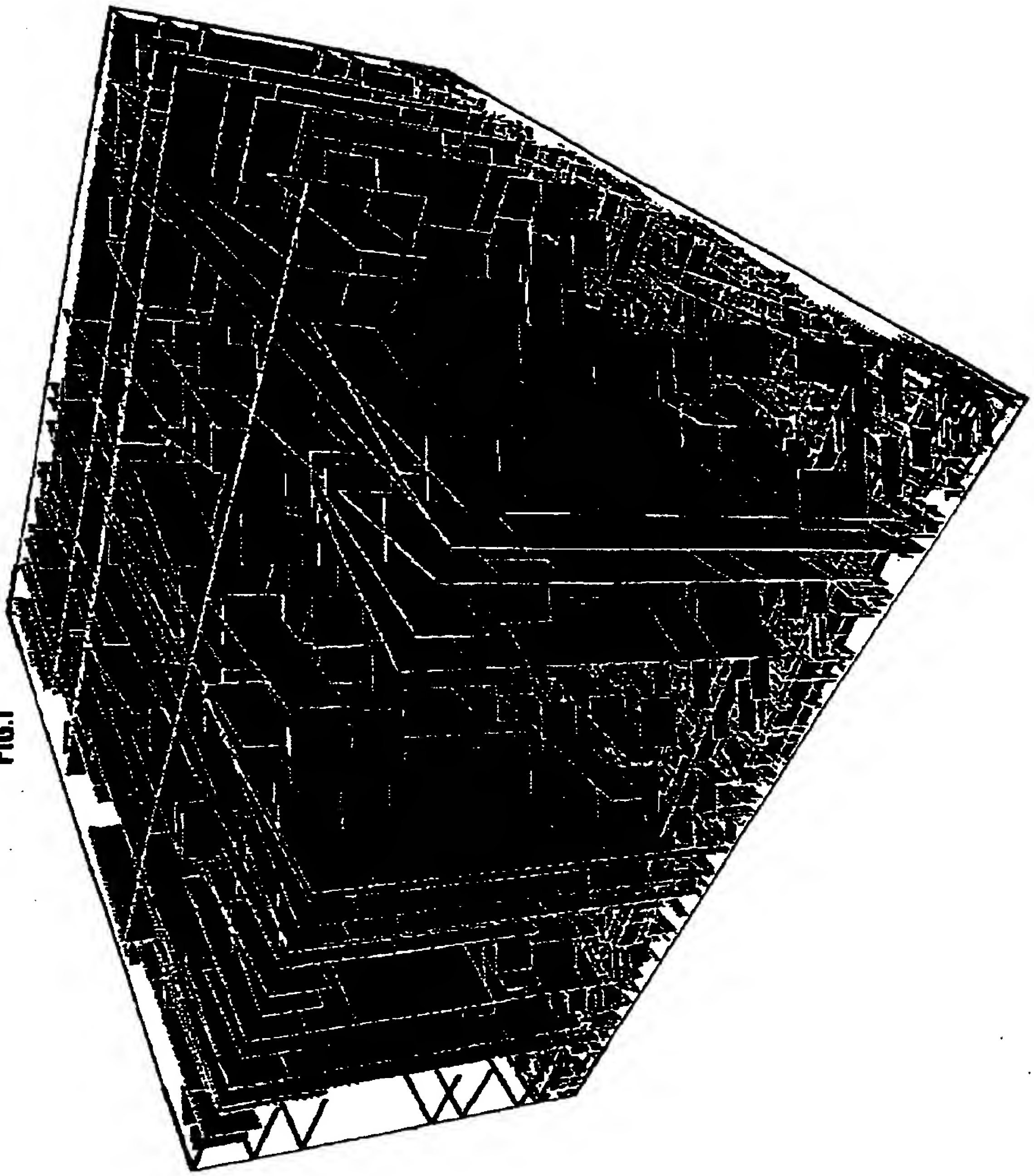


FIG.1

FIG.3

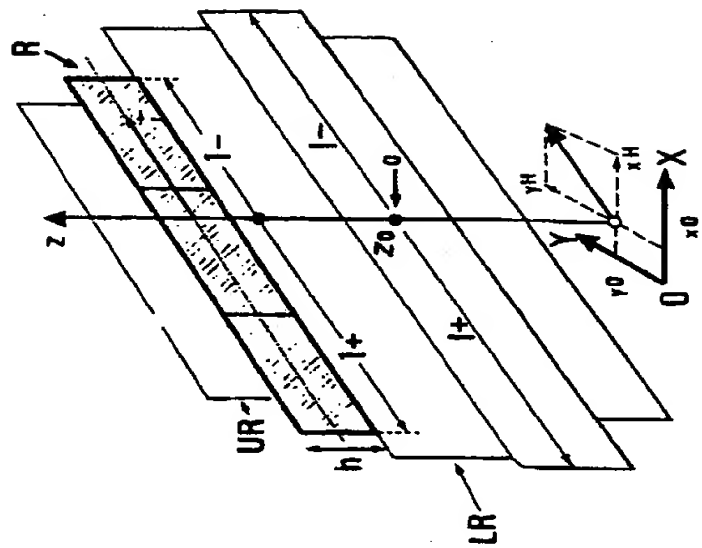


FIG.2

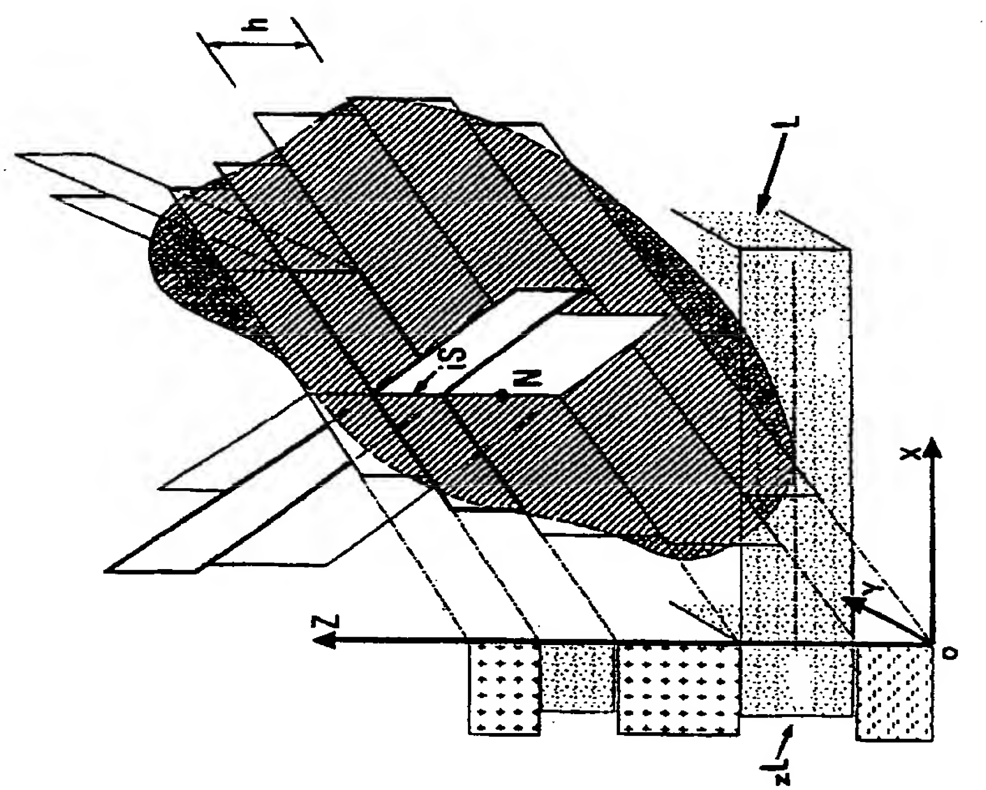
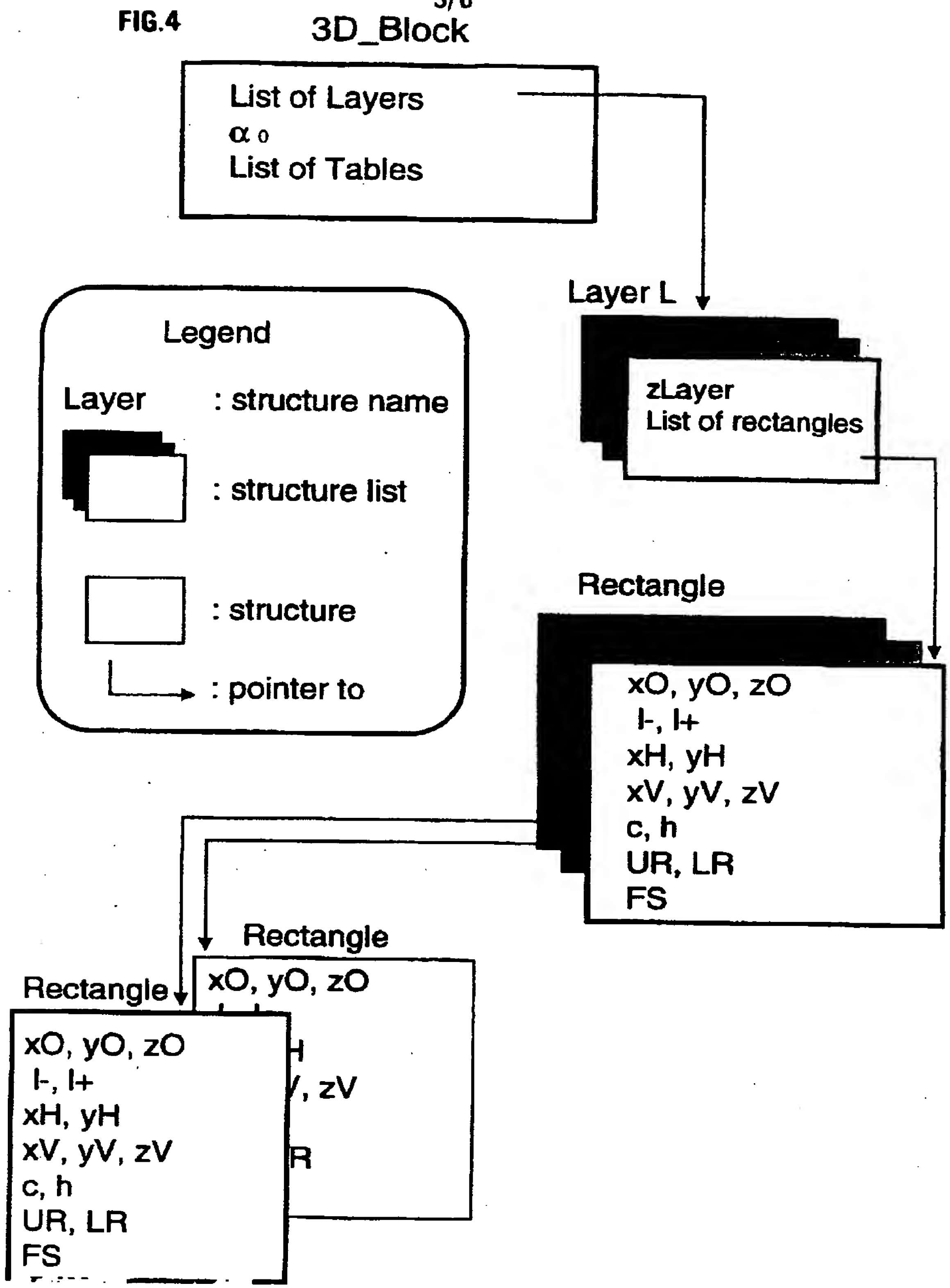


FIG.4


3D_Block
List of Layers
α o
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Layer L
zLayer
List of rectangles
Legend
Layer : structure name
: structure list
: structure
: pointer to
Rectangle
xO, yO, zO
l-, l+
xH, yH
xV, yV, zV
c, h
UR, LR
FS
Rectangle
xO, yO, zO
Rectangle
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FIG.5

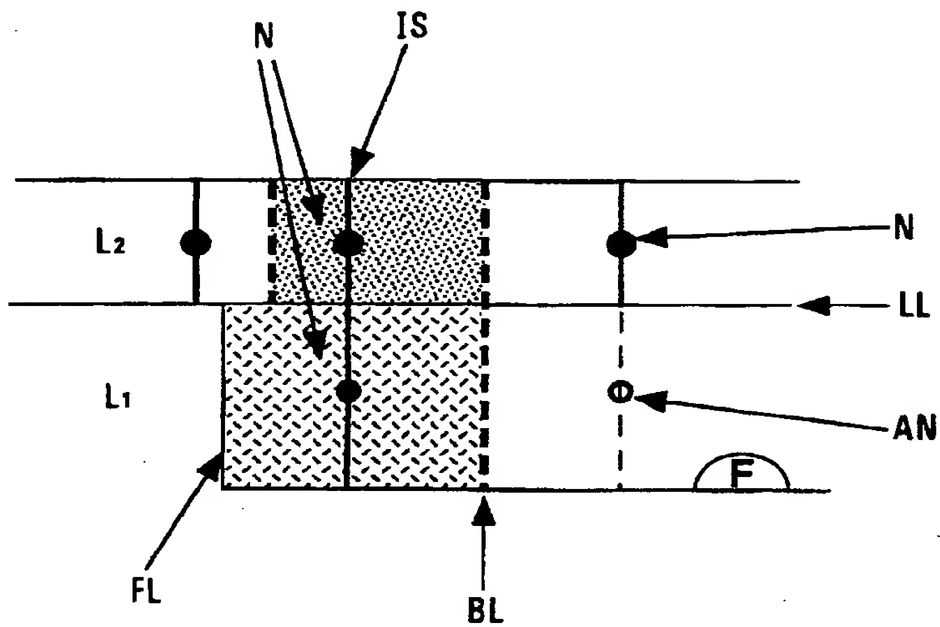
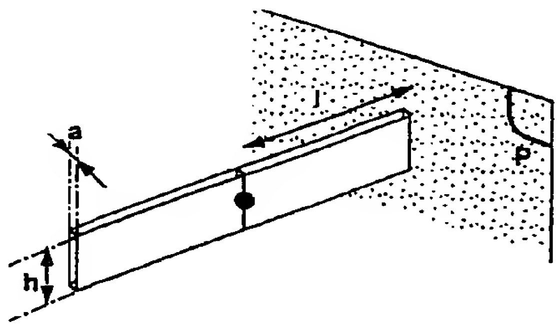
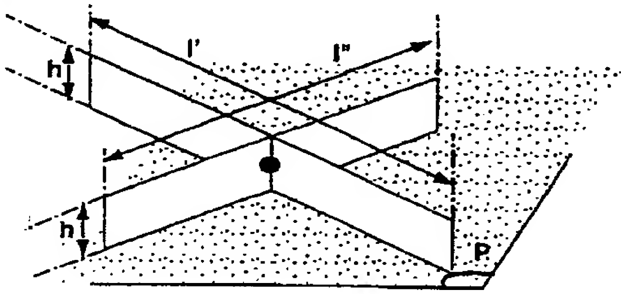


FIG.6



$$T = \frac{h\,k\,a}{l}$$

FIG.7



$$T = \frac{2(l'k'a' + l''k''a'')}{h}$$

FIG.8

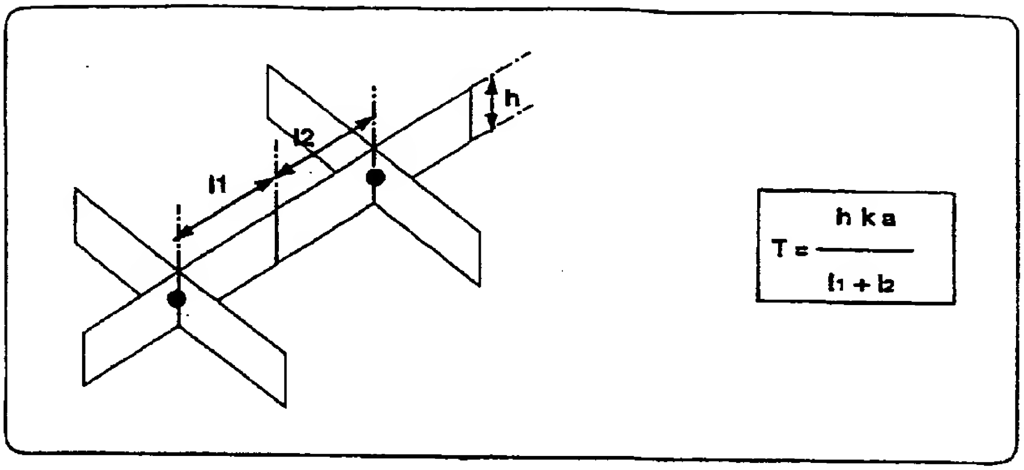
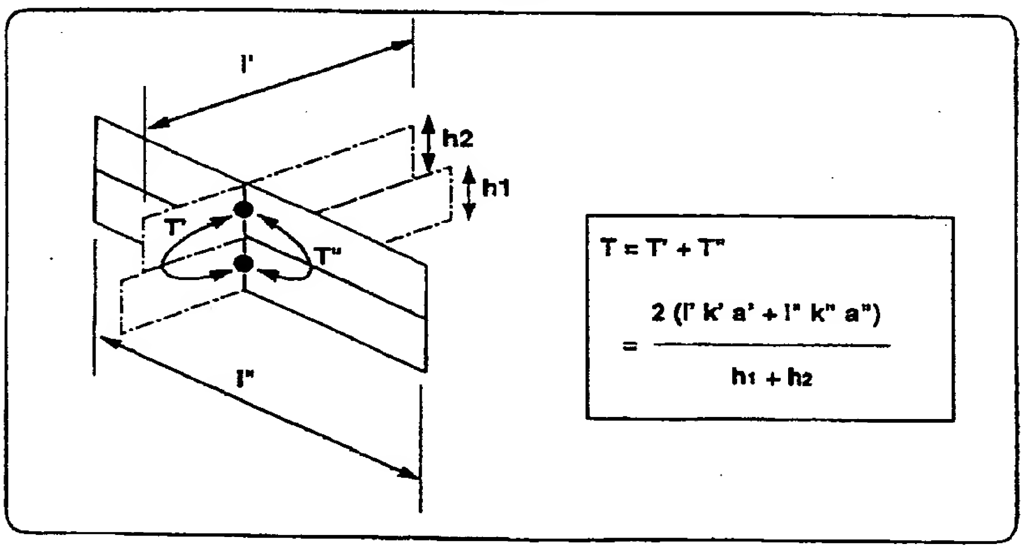


FIG.9



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METHOD OF DETERMINING THE EQUIVALENT PERMEABILITY OF A FRACTURE NETWORK IN A SUB-SURFACE, MULTI-LAYERED MEDIUM

The invention relates to a method of determining the equivalent fracture permeability of a fractured network in a sub-surface multi-layered medium, which can be used to build a more realistic model of a fractured sub-surface geological structure. The method can be used by reservoir engineers as a means of producing reliable predictions of oil flows, for example.

Fractured reservoirs are an extreme type of heterogeneous reservoirs made up of two contrasting media, a matrix medium containing the majority of the oil and of a low permeability and a fractured medium accounting for less than 1% of the oil in place and highly conductive. The fractured medium itself may be very complex having different fracture sets, each characterised by its density, length, orientation, tilt and aperture. 3D images of fractured reservoirs can not be used directly in the form of input data for simulating a reservoir. It has long been considered unrealistic to represent fracture networks within reservoir flow simulators because the layout of the network is partially unknown and because of the numerical limitations inherent in juxtaposing numerous cells of extremely contrasting sizes and properties. A

simplified but realistic way of modelling such media would therefore be of great interest to reservoir engineers.

The "dual porosity approach", as taught, for example, by Warren J.E. et al in "The Behaviour of Naturally Fractured Reservoirs", SPE Journal (September 1963), 245-255, is known in the art as a means of interpreting single-phase flow behaviour observed when testing a fractured reservoir. In accordance with this basic model, any elementary volume of the fractured reservoir is modelled in the form of a set of identical parallelepipedic blocks limited by an orthogonal system of continuous uniform fractures oriented in the direction of one of the three main flow directions. On the reservoir scale, fluid flows through the fractured medium only and fluid exchanges occur locally between the fissures and the matrix blocks.

Numerous simulators have been developed for fractured reservoirs using a model of this type with specific improvements in respect of the way flows are exchanged between matrix and fracture, governed by capillary, gravitational and viscous forces and compositional mechanisms as well as matrix-to-matrix flow exchanges (dual-permeability dual-porosity simulators). Numerous examples of prior art techniques are cited in the reference works listed below.

Thomas, L.K. et al: "Fractured Reservoir Simulation", SPE Journal (February 1983) 52-54;

Quandalle, P. et al: "Typical Features of a New Multipurpose Reservoir Simulator", SPE 16007, presented at the 9th Symposium on reservoir simulation held in San Antonio, Texas, 1-4 February 1987;

Coats, K. H.: "Implicit Compositional Simulation of Single-Porosity and Dual-Porosity Reservoirs", SPE 18427 presented to the SPE Symposium on reservoir simulation held in Houston, Texas, 6-8 February 1989.

One of the problems which reservoir engineers encounter is that of applying parameters to this basic model in order to produce reliable flow predictions. The basic petro-physical properties of fractures and matrices and the size of the matrix blocks in particular must be ascertained for each cell of the flow simulator. Whilst the permeability of the matrix can be estimated from cores, there is no simple method of estimating the permeability of the fracture network contained within the cell, i.e. the equivalent fracture permeability and it is necessary to take account of the geometry and properties of the fracture network.

One direct method is known whereby steady-state flow is determined in a fracture network. It consists in using conventional fine and regular grids to divide up both the fractures and the matrix blocks of the parallelepipedic rock volume considered. For various

reasons, this known method does not produce reliable results unless the volume of fractured rock is divided using a grid with an extremely high number of cells, which requires enormous computing resources.

Other specific models which compute equivalent permeabilities of 2D or 3D fracture networks, for example, are also known from:

- Odling, N.E.: "Permeability of Natural and Simulated Fracture Patterns", Structural and Tectonic Modelling and its Application to Petroleum Geology, NPF Special Publication 1, 365-380, Elsevier, Norwegian Petroleum Society (NPF) 1992;

- Long, J.C.S.: et al: "A Model for Steady Fluid Flow in Random Three-Dimensional Networks of Disc-Shaped Fractures", Water Resources Research (August 1985), vol. 21, 8, 1105-1115;

- Cacas, M.C. et al: "Modelling Fracture Flow with a Stochastic Discrete Fracture Network : Calibration and Validation. 1. The Flow Model", Water Resources Research (March 1990) vol. 26, 3;

- Billaux, D. : "Hydrogéologie des milieux fracturés. Géométrie, connectivité et comportement hydraulique", Doctoral thesis presented to the Ecole Nationale Supérieure des Mines de Paris, BRGM document 186, Editions du BRGM, 1990;

- Robinson, P.C.: "Connectivity, Flow and Transport in networks, Models of Fractured Media",

Doctoral thesis, St Catherine's College, Oxford University, Ref.: TP1072, May 1984.

The present invention relates to a method of determining the equivalent fracture permeability of a fracture network in a sub-surface, multi-layered medium.

The method is characterised in that it consists of the following steps:

- the fracture network is split up into fracture elements (such as rectangles, for example) and nodes are defined to represent inter-connected fracture elements in each layer of the medium and

- fluid flows through the divided network are determined by imposing boundary pressure conditions and fluid transmissivities to each pair of adjacent nodes.

More specifically, the method is characterised in that:

- the medium is divided into a series of parallel layers, each extending in a reference plane perpendicular to the reference axis and defined by a coordinate on the said axis,

- each fracture is divided into a series of rectangles limited by two adjacent layers along the said reference axis and the rectangles are itemised by attributing geometric and physical characteristics to them such as coordinates and sizes of the rectangles and hydraulic conductivities of the fractures,

- nodes are placed in each layer for all the inter-connected fractures, and

- transmissivity factors are computed and flow equations solved for all the pairs of adjacent nodes in order determine the equivalent permeabilities of the medium in three orthogonal directions.

In a preferred embodiment, the equivalent permeability of the medium includes directly determining the equivalent permeability anisotropy tensor and calibrating absolute permeability values using well test results.

The method as summarised allows characteristic models of fractured reservoirs to be systematically linked with dual porosity simulators in order to produce a more realistic model of a sub-surface, fractured geological structure. The method can be implemented by reservoir engineers in the field of petroleum production as a means of providing reliable flow predictions.

Other features and advantages of the method of the invention will become clearer from the following description of embodiments, given by way of example and not restrictive in any respect, and with reference to the appended drawings, in which:

figure 1 shows a 3D image of a fracture network, for example, stochastically generated from observations of and measurements taken on a sandstone outcrop,

figures 2, 3 illustrate a fracture divided into a series of rectangles R,

figure 4 shows the structure of input data specifying the fracture attributes,

figure 5 shows the preferred method of dividing up a fracture plane,

figures 6, 7, 8 and 9 provide a schematic illustration of how transmissivity factors are computed for different positions of nodes relative to one another or with a boundary.

The equivalent permeabilities of a 3D fracture network are determined below using a numerical technique based on the known "resistor network" method, described for example in the publication by Odling, N.E., mentioned above. With this method, the matrix is assumed to be impermeable so as to be consistent with the dual porosity approach. In reservoir simulators, matrix-to-fracture and matrix-to-matrix flows are actually computed separately from flows within the fractures.

The 3D fracture network considered is assumed to represent, in a volume equal to a reservoir cell, the real distribution of fractures produced by integrating fracture attributes of the field in a characterisation model. The main purpose of single-phase flow computations in the 3D fracture network is to estimate the equivalent permeability anisotropy (Kv/Kh and

Ky/Kx) of the fracture cell considered, which is an important parameter governing the behaviour of multi-phase flows in reservoirs. The equivalent permeability values obtained by these computations could in practice be compared with the results of well test as a means of calibrating fracture attributes such as fracture hydraulic conductivities (or equivalent hydraulic apertures), which a priori can be defined to a mediocre standard only.

The equivalent permeability results can also be used to determine a permeability tensor, the main directions of which will enable optimum orientation of the reservoir model grid. However, specific boundary conditions are needed in order to obtain this information. Lateral no-flow boundary conditions imposed on the four lateral faces of the parallelepipedic volume under study do not give access to non-diagonal terms of the equivalent permeability tensor whereas linearly varying potentials (or pressures) across the lateral faces will allow the direction of potential gradient within the anisotropic medium to be imposed and the non-diagonal permeability terms of lateral flows to be derived directly.

The techniques used to integrate natural fracturing data into fractured reservoir models are well known. Fracturing data are essentially geometric in nature and incorporate measurements of the density,

length, azimuth and tilt of fracture planes either as observed from outcrops, mine drifts or cores or inferred from well logging. Different fracture sets can be distinguished and characterised by different statistical distributions of the fracture attributes. Once the fracture patterns have been characterised, numerical networks of these fracture sets can be created using a stochastic method consistent with the statistical distributions of the fracture parameters. Such methods are described in patents FR-A-2.725.814, 2.725.794 or 2.733.073 filed by the applicant, for example.

The method of the invention is applied to images of fractured geological structures of various sizes or volumes and/or at various locations which are generated by a fracture model. Figure 1 illustrates such an image.

INPUT DATA

Before developing the procedures recommended as a means of determining the equivalent hydraulic parameters of 3D fracture images, a major step consists in defining a common structure for the input data to be applied to these images so that they can be processed independently of the processing tool used to generate them.

As shown in figures 2, 3, it is assumed that the fractures F are essentially vertical (i.e.

perpendicular to the layer limits). However, a same data structure can be applied to fractures which deviate slightly from the vertical. The 3D image is divided vertically, complying with the actual geological layering if this information is available. Otherwise, an arbitrary division is applied to the image. Each horizontal layer L is characterised by its vertical coordinate zL in the reference system of coordinates (OX, OY, OZ).

A series of rectangles R must be defined for each layer L. Each rectangle consists of a fracture plane element between the limits of a given layer. Consequently, each natural fracture consists of a series of superposed rectangles R and is assigned an origin (origin of the fracture). Each rectangle is defined by:

- the three coordinates (xO, yO, zO) of the origin of the rectangle O. All the origin points of the rectangles making up any given natural fracture are located on the same vertical line (or highest dip) plotted from the origin of the fracture;

- the coordinates of the horizontal unit vector $\vec{i}$ (xH, yH) and the vertical unit vector $\vec{j}$ (xV, yV) defining the orientation of the rectangle within the reference system of coordinates, where xVertical and yVertical are equal to zero in the case of vertical

fractures but are considered as input data in order to be able to deal with non-vertical fractures;

- the two algebraic horizontal lengths l- and l+ separating the origin of the rectangle and the two lateral (vertical) limits of this rectangle;

- the height h of the rectangle, i.e. the length of the rectangle in the direction $\vec{j}$, which is the thickness of the layer if the division in direction $\vec{j}$ corresponds to the geology;

- the hydraulic conductivity c derived by applying Darcy's law on fracture flow (for a pressure gradient $\frac{\Delta P}{l}$, the flow rate in the fracture of a height h is

$\frac{ch}{\mu}.\frac{\Delta P}{l}$, where μ is the viscosity of the fluid). The conductivity c is given by the relationship c=k.a, where k = $a^2/12$ (using Poiseuille's idealised representation of fractures) is the intrinsic permeability of the fracture and a its equivalent hydraulic aperture. The hydraulic conductivity c is a reference value given for a direction of the maximum horizontal stress parallel with the direction of the fracture;

- the two upper and lower adjacent rectangles UR, LR;

- the fracture series FS to which the considered rectangle belongs;

- the angle of orientation α_0 of the direction of maximum horizontal stress taken from the axis (OX) within the reference system of coordinates;

- for each series of fractures, a correlation table correlating 1) the angle between the direction of maximum horizontal stress and the direction of the fracture (azimuth) with 2) the hydraulic conductivity c of the equivalent hydraulic aperture a previously defined. The terms "horizontal" and "vertical" used in this context relate to the respective directions parallel with and perpendicular to the layer limits, which are assumed to be horizontal in this case. The layer limits divide the fracture plane in the "vertical" direction. It should be pointed out that the above-mentioned input data 1) are suitable for all the existing software tools used to characterise and generate fractures and 2) could be used to divide up a network of fractures slightly off from the vertical, i.e. which are not perpendicular to the layer limits.

OPERATING PROCEDURES

The operating procedures and validation tests for the method used to compute the permeability anisotropy of the fracture network taken as a whole are described below using the 3D image coded in this way. The numerical procedure used to compute the equivalent permeabilities of a 3D fracture network will also be described.

The problem consists in finding the distribution of flow rates in the network for the following boundary conditions imposed on the limits of the parallelepipedic volume studied, i.e. fixed pressures imposed on two opposing faces and pressures varying linearly across the four lateral faces (between the values imposed on the other two faces).

The main steps are set out below:

1) Dividing up the network

Using the definitions given for the input data structure, the fracture network is divided up into a series of "nodes" N, each node being positioned at the centre of the intersecting segments IS of two rectangles R (i.e. of two fracture planes within a given layer). As illustrated in figure 5, additional nodes AN are positioned above and below the preceding nodes N in order to represent other rectangles dividing up the fractures and minimising the flow lengths within a given fracture. In figure 5, BL is a lateral limit of two adjacent fracture cells.

Once the network has been divided up, a screening procedure is applied to this fracture network in order to eliminate isolated nodes or groups of nodes with no link to one of the lateral limits FL of the 3D volume studied since the fissures "screened" in this way do not contribute to fluid transport and may impede the computational procedures used to find the pressures at

fracture nodes during a steady-state flow through the network.

2) Calculating transmissivities

A transmissivity factor T is calculated for each pair of connected nodes using the relationship:

$$T = \frac{ch}{l} = \frac{kah}{l}$$

where c is the hydraulic conductivity of the fracture, k the intrinsic permeability of the fracture, a the aperture of the fracture, h the height of the fracture and l the distance between two nodes of a fracture.

Different situations have to be considered depending on the respective position of the two nodes. For nodes contained within the same layer (fig. 6) the horizontal transmissivity factor T is obtained directly in the form of the distance (l1+l2) separating the two nodes in the flow direction (fig. 7). In the case of nodes located in two different layers (fig. 9), the horizontal transmissivity factor is the arithmetic sum of the transmissivity factors (T'+T") relating to the two fracture plane elements of the superposed fracture cells. It comprises a flow length equal to half the sum of the two layer thicknesses h1 and h2. For the additional nodes as previously defined, a single

transmissivity factor is calculated for this fracture plane element.

The transmissivity factor T between a node and a limit of the 3D volume studied is expressed in the same way as between two nodes, depending on one of the following two situations.

In the case of a lateral vertical limit, the transmissivity factor T can be expressed directly for a single fracture plane element (fig. 8) and takes the form of the sum of two transmissivities if the node and the limit are linked by two fracture planes.

In the case of a horizontal upper or lower limit, the vertical transmissivity factor can be expressed by taking a flow length equal to half the thickness of the layer (fig. 9).

3) Flow equations

In steady state, an incompressible single-phase flow through the fracture network is determined by solving a series of n equations, one for each node, well known in the art. Each equation expresses the fact that the total flow rate is zero at each fracture node. In order to calculate a permeability tensor, a constant pressure is imposed on each of the limits upstream and downstream. A pressure is imposed which varies linearly as a function of the position between the upstream and downstream limits.

The equivalent permeability matrix (Kij) determined previously is diagonalised in order to calculate the main flow directions with the respective equivalent permeabilities in these directions.

In practice, the problem is often limited to finding the main horizontal flow directions U and V given that the direction perpendicular to the layer limits (generally vertical) is always taken as the z axis. In such a case, only the extra-diagonal terms K_{xy} and K_{yx} need to be calculated: they can be obtained with the following mixed boundary conditions:

- horizontal flows are computed with impermeable top and bottom faces and pressures varying linearly on the vertical faces parallel with the flow direction;

- vertical flow is computed with all lateral faces being impermeable.

A simplified permeability tensor is thus obtained, from which the main horizontal flow directions U and V can easily be derived:

$$\begin{pmatrix} K_{xx} & K_{yx} & 0 \\ K_{xy} & K_{yy} & 0 \\ 0 & 0 & K_{zz} \end{pmatrix}$$

Validation

The method has been successfully validated against the above-mentioned reference single-phase flow geometry.

computations performed with a conventional reservoir simulator. The reference computations were produced on fine regular grids dividing up the fractures as well as the matrix blocks of the parallelepipedic fractured rock volume considered. For a given flow direction, a fixed injection pressure and production pressure were imposed on the inlet and outlet faces and the resulting flow rate was calculated for conditions under which there is no lateral flow.

Three steps were performed to validate the computation of:

- the equivalent vertical permeability of a volume of rock crossed by a single fracture, this latter being represented by several nodes corresponding to intersections with small disconnected fractures;

- the equivalent horizontal permeabilities (in a 2D flow geometry) and the main flow directions;

- the equivalent permeabilities and permeability anisotropy in a single network involving 3D flow geometry.

The results obtained for the third step (for a 3D flow geometry) are set out in the table below. A reference analytical solution can also be computed for the horizontal flow directions since the flow geometry is a 2D flow geometry in these directions (the 3D flow geometry relates to the z direction).

Equivalent permeabilities (md)	FINE GRID simulation	PRESENT METHOD	ANALYTICAL solution
Kx	0.119	0.120	0.120
Ky	0.224	0.227	0.226
Kz	0.255	0.267	
Anisotropy $Kz/(KxKy)^{0.5}$	1.56	1.62	

The results produced by the present method are clearly very close to the corresponding values obtained using the analytical solution and the fine grid solution for the directions X and Y.

Furthermore, the difference between the vertical equivalent permeability values relating to 3D flow is still acceptable. Hence, the anisotropy ratio, which is 1.6, is satisfactorily predicted by the method with a very limited number of cells.

The method of the invention, which provides a readily transposed representation of a natural fracture network is well suited to fracture flow computations. It may also prove useful in improving the original image of the fracture network. Such an image is in fact obtained from a stochastic fracture generator using as input data the results produced by integrating filed fracture data in a fracture characterisation model as

described in patents FR-A-2.725.814, 2.725.794 or 2.733.073 filed by the applicant, mentioned above. Once divided up by the method of the invention, such images can easily be modified to fit the geological rules. For example, the systematic interruption of a given fracture against any other series of fractures can be taken into account in the original image by eliminating fracture plane elements from a given set extending beyond the intersected fractures of the other set.

CLAIMS

1. A method for determining the equivalent fracture permeability of a fracture network in a sub-surface, fractured, multi-layered medium from a predetermined representation of said network, comprising the steps of:

- dividing each fracture (F) in the fracture network into fracture elements and defining nodes (N) representing inter-connected fracture elements in each layer of the medium and

- determining fluid flows through the fracture network, imposing boundary pressure conditions, and fluid transmissivities for each pair of adjacent nodes.

2. A method as claimed in claim 1, characterised in that:

- the medium is divided into a series of parallel layers each extending in a reference plane perpendicular to the reference axis and each defined by a coordinate on said axis,

- each fracture is divided into a series of rectangles limited on said reference axis by two adjacent layers and the rectangles are itemised by attributing geometric and physical characteristics to them such as rectangle coordinates and sizes and hydraulic conductivities of the fractures,

- nodes are placed in each layer for all the inter-connected fractures and

- transmissivity factors are computed and flow equations solved for all the pairs of adjacent nodes in order to determine the equivalent permeabilities of the medium in three orthogonal directions.

3. A method as claimed in one of the preceding claims, characterised in that the equivalent permeability of the medium includes directly determining an equivalent permeability tensor and calibrating absolute permeability values from well test results.

4. A method as claimed in one of the preceding claims, characterised in that said geometric and physical attributes are the coordinates and dimensions of the rectangles and the hydraulic conductivities of the fractures.

5. A method as claimed in any preceding claim and as hereinbefore described with reference to the accompanying drawings.

The Patent Office

22

Application No:	GB 9727227.2	**Examiner:**	Mike Davis
Claims searched:	1-5	**Date of search:**	2 July 1998

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.P): G4A (AUA, AUXX)

Int Cl (Ed.6): G06F, G06G, G01V

Other: Online: WPI

Documents considered to be relevant:

Category	Identity of document and relevant passage	Relevant to claims
	None	

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.